Recent Advances in Air Pollution Control Technologies for Coal-fired Power Plants

Alberta Environment

Recent Advances in Air Pollution Control Technologies for Coal-fired Power Plants

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prepared for:

Alberta Environment

September, 2006

CEM 10415-2007

ISBN: 978-0-7785-7334-0 (Printed)
ISBN: 978-0-7785-7335-7 (On-line)
Web Site: http://www.environment.alberta.ca/

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EXECUTIVE SUMMARY

Coal continues to be an important fuel worldwide for the generation of electricity. A previous report by the author reviewed technologies available or under development to minimize the amount of air pollutants and greenhouse gases emitted from coal-fired power plants. This report discusses further developments and improvements since 2001 in air emissions control technology.

Improvements have continued in either reducing the cost and/or improving the performance of the major emissions control technologies discussed in the 2001 report. Most new installations in developed countries are pulverized coal combustion plants operating with supercritical steam conditions. The predominant methods for controlling emissions of the major pollutants are:

- limestone based wet flue gas scrubbers for control of SO_2 emissions from high sulphur coals,
- lime based spray dry absorbers for control of SO_2 from low sulphur coals,
- low NO_x burners for control of NO_x, followed by Selective Catalytic Reduction (SCR), if required, to achieve lowest NO_x levels, and
- electrostatic precipitators or baghouses for the control of particulates.

Emission levels achieved in commercial plants have improved since the 2001 report. New coal-fired plants with advanced conventional flue gas desulphurization (FGD) systems can achieve SO_2 emissions less than 40 g/GJ. A recent plant in Italy will have a guarantee of monthly average SO_2 of 30 g/GJ. Similarly improvements in the design and operation of low NO_x burners for corner fired utility boilers have resulted in NO_x emission levels of 65 g/GJ. Commercial installations of Selective Catalytic Reduction systems have achieved NO_x outputs levels of about 24 g/GJ in the U.S. and about 11 g/GJ in Japan.

A further significant reduction in pollutant emissions can be achieved with Integrated Gasification Combined Cycle (IGCC) systems. There are several commercially operating IGCC plants in the world, however IGCC plants still do not have the reliability or the rapid time to start up time of conventional coal plants and are 10 to 20% more expensive to build. Since the 2001 report, the United States has announced financial incentives for new gasification installations. As a result, a large number of new IGCC plants are planned in the United States, including facilities that will separate and recover CO_2. The operating Polk IGCC plant has achieved emission levels of 52 g/GJ for SO_2, 17 g/GJ for NO_x and less than 1.7 g/GJ for particulate.

Other emissions reduction technologies that may be commercially demonstrated in the next five to ten years include:

- process modifications and/or additives to enable co-capture of mercury and NO_x in flue gas desulphurization scrubbers,
- activated carbon injection for mercury control,
- wet electrostatic precipitators for better removal of particulates, and
- systems to separate and recover CO_2 from coal combustion flue gas.

Since the 2001 report the United States has initiated a major long term demonstration project termed 'FutureGen'. The objective of this $1 billion project is to build a commercial scale coal-fired power plant that will generate both electricity and hydrogen with near zero emissions to the air. The plant will use coal gasification combined cycle technology and would include the separation and capture of CO_2. At the time of this report, the United States Department of Energy was considering a short list of four locations for construction of the FutureGen demonstration plant.

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1.0 BACKGROUND

In 2001, the Alberta Research Council performed a review for Alberta Environment of technology options available or under development for the reduction of air pollutant emissions from coal-fired power plants. This review was summarized in the document 'Technical Advice on Air Pollution Control Technologies for Coal-fired Power Plants' (Chambers, 2001). Since that time, technology has continued to develop for reducing emissions to the air from generation of electricity using coal as a fuel.

The majority of technology development for coal-fired power plants continues to occur in the United States, Europe, or Japan. The system and units for reporting emissions varies. Most information from the United States is reported in British units. Efficiency of conversion of coal energy to electricity may be reported based on the higher heating value (HHV) of the coal or the lower heating value (LHV). Emissions may be expressed on the basis of concentration in the stack gas, mass of emissions per unit of energy input or mass of emissions per unit of electricity produced. Where possible, information reported in the following review has been converted to metric units and the HHV system.

The reduction of emissions of NO_x, SO_x, particulates, and mercury from coal-fired electricity production is an active area in technology development with significant research and development funding. The majority of new technology developments are occurring in the U.S., Europe, or Japan. These regions have strict emissions regulations and significant government funding for low emissions technology development. The U.S. Department of Energy lists over sixty environmental control projects as of January 2006 (www.fossil.energy.gov/fred/feprograms.jsp?prog=Adv.+Power+-+Environmental+Control+Technologies).

Several Canadian groups are also examining technologies to reduce air emissions from coal-fired electricity generation. The Canadian Clean Power Coalition (www.canadiancleanpowercoalition.com) is an association of Canadian coal and coal-fired electricity producers and the U.S. based Electric Power Research Institute. The Coalition's mandate is to research, develop and demonstrate commercially viable clean coal technology that captures all air emissions, including carbon dioxide, with a demonstration plant constructed by 2012. Other activities in Canada include:

- CANMET Energy Technology Centre work in O_2/CO_2 recycle combustion,
- University of Regina activities for improved CO_2 capture from coal combustion, and
- Alberta Research Council Inc. activities in developing new technology for CO_2 separation and for CO_2 sequestration in geological formations.

2.0 SCOPE

The main objective of this project was to update the current status of new technology developments for the control of emissions from coal fired power production. Most of the technologies discussed were identified in the previous report (Chambers, 2001). Gasification of coal for the purpose of electric power generation was an area of focus for this update.

The following report summarizes information on:

- recent updates on technologies available for the control of SO_x, NO_x, particulate, and Hg emissions, considering the properties of Alberta coals, and emission levels achievable with these technologies,
- new developments in commercial applications of coal gasification for electric power generation, and
- new developments in greenhouse gas capture from coal combustion and gasification systems.

3.0 COAL PROPERTIES

Converting coal to electricity by combustion or gasification results in emissions of CO_2 (a greenhouse gas), SO_x, NO_x and particulates. CO_2 is produced by combustion of carbon in the coal. SO_x emissions are largely determined by the sulphur content of the coal. NO_x emissions are partly a function of nitrogen content of the coal but are primarily determined by combustion conditions. Particulate emissions are determined by coal ash content, particle size of the coal after grinding, ash composition, and boiler conditions. Fine particulate emissions (PM10 and PM2.5) also can be a result of atmospheric reaction of SO_2, NO_x and ammonia to form secondary particles downwind of the power plant (Sloss, 2004).

Alberta coals typically used for mine-mouth power plants are sub-bituminous in rank with a relatively low heating value. Despite the low heating value, these coals have several properties that are an advantage for power generation, including:

- low sulphur content, typically <0.5% as compared to 3% for eastern U.S. bituminous coal,
- high combustion reactivity,
- relatively low trace metals content, and
- high calcium in ash leading to some inherent sulphur capture in the ash.

Coal properties can have a significant impact on selection of the best technology for the control of air emissions from coal-fired power generation. The following discussion will identify if a technology that may not be appropriate for Alberta sub-bituminous coals.

4.0 OTHER CONSIDERATIONS

This report summarizes information on technologies for the control of air emissions from coal-fired electricity production. Control of these emissions is needed due to their potential negative impact on the environment and human health. Coal-fired electricity production also produces solid and liquid wastes that may also have negative impacts. Developing regulations to set limits on emissions of the individual air pollutants is a complex process that must consider interactions between air pollution control methods, implications for liquid and solid waste disposal and the cost/benefits of control of each pollutant. For example, reducing the allowable sulphur dioxide (SO_2) emissions from power plants using current flue gas desulphurization technology would typically result in an increase in the cost of electricity to the consumer, an increase in emissions of the greenhouse gas CO_2 and an increase in solid wastes for disposal.

The following discussion of air pollution control technologies is divided into short term technologies and mid-term technologies based on the commercial demonstration of the technology. Short-term technologies are those that have been demonstrated at full scale and are commercially available. Commercial availability does not necessarily infer that the technology is cost effective. The cost effectiveness of a technology is a complex judgment based on the projected environment and health benefits of further emissions reductions for each individual pollutant. Costly technologies that can achieve the lowest possible emissions, such as Selective Catalytic Reduction units for reducing NO_x, may be considered cost effective in a region with high population density and poor air quality but may not be considered cost effective in other regions.

5.0 SHORT-TERM TECHNOLOGIES

Short-term technologies are those technologies currently available commercially and previously demonstrated with proven reliability at a commercial scale. Over 90% of new coal-fired power plants are pulverized coal combustion units (PCC) over 300 MW in size. The trend in developed countries is to install supercritical steam PCC units (SCPC) as they are 2 to 3% more efficient in converting coal to electricity. Fernando, 2004, reports that in 2002 the number of installations of supercritical units surpassed sub-critical steam units worldwide. Circulating fluidized bed combustion (CFBC) units make up only 2% of the worldwide market and are typically selected for difficult fuels such as high moisture and ash coals.

Very few coal-fired plants were constructed in the 1990's leading to a significant consolidation of power plant equipment suppliers. With recent increases in oil and natural gas prices in North America the situation has changed with increased activity in the United States to retrofit old plants and build new coal-fired power plants. Coal-fired power plants produce 55% of the electricity in the U.S. and there are over 450 coal-fired power plants. Many of the retrofit projects are installing improved emissions control equipment, including low NO_x burners, SO_2 scrubber systems, and mercury control systems, in order to meet tightened emissions regulations. This scenario will likely continue due to large and secure reserves of coal in the U.S.

Commercially available technologies to reduce emissions of SO_x, NO_x and particulates from coal-fired power plants were discussed in the previous report (Chambers, 2001). The following will discuss recent significant developments in these technologies that have reduced their cost and/or improved their performance. The discussion focuses on technologies relevant to a PCC or SCPC plant fired with low sulphur, sub-bituminous coal typical of that used in Alberta for the generation of electricity.

5.1 SO_2 Reduction

The primary means of reducing SO_2 produced by the combustion of coal is by reacting the gaseous combustion products with calcium compounds such as limestone and dolomite. This reaction can take place during combustion, as in fluidized bed systems, or by treating the flue gas, as in flue gas desulphurization systems.

5.1.1 SO_2 Reduction by Flue Gas Treatment

Sulphur in coal is converted to SO_2 during combustion and released with the flue gas. Flue gas desulphurization (FGD) is the currently accepted means to reduce emissions of SO_2 in PCC and SCPC systems. FGD has been in commercial use in various forms since the 1970's. FGD can also contribute to reducing emissions of trace elements including some forms of mercury. The majority of commercial FGD processes use calcium-based sorbents, either limestone or lime, and can be categorized as:

- wet scrubbers, or
- spray dry scrubbers.

The sorbent combines with SO_2 to form a solid waste material. Some wet scrubber systems produce a saleable gypsum by-product or other construction materials if a suitable market is located nearby. Due to the potential to form gypsum and to remove up to 99% of the SO_2, wet scrubbers currently have 87% of the world share of FGD installations.

New PCC plants with advanced conventional FGD systems can achieve SO_2 emissions less than 100 mg/m^3 (at stack gas concentrations of 6% O_2, dry) or about 37 g/GJ. A recent plant in Italy will have a guarantee of monthly average SO_2 of 80 mg/m^3 or about 30 g/GJ (Henderson, 2005).

Spray dry scrubbers inject a lime-water slurry into the flue gas such that the water evaporates and the lime reacts with SO_2 to form dry calcium sulphite/sulphate. These solids are then removed along with the flyash in a baghouse. SO_2 removal levels of 95% are achievable. Spray dry scrubbers have lower capital costs than wet scrubbers but higher sorbent costs. Spray dry scrubbers are used with low sulphur coals or as an additional SO_2 removal step for fluidized bed units.

There is an increased interest in SO_2 scrubbing systems that produce fertilizer as a saleable byproduct rather than a waste for landfill. The economics of these systems strongly depend on the local cost of sorbent chemical and a market for the fertilizer. Ammonia can be used as a sorbent to produce an ammonium sulphate fertilizer product, such as the ammonia based scrubbing system offered by Marsulex (www.marsulex.com). Airborne Technologies has a process at the demonstration scale that uses dry sodium bicarbonate coupled with wet sodium scrubbing to control SO_2, NO_x, and Hg emissions (Johnson, et al., 2005). The system produces an ammonium sulphate fertilizer product and a carbon dioxide stream and regenerates the spent sodium carbonate for reuse. The process has been demonstrated at the scale of 5 MW.

Technical improvements continue in FGD systems both to improve SO_2 capture and to reduce capital and operating costs. The Electric Power Research Institute (EPRI, website www.epri.com) is evaluating new novel liquid/gas contactors, additives to improve performance and the potential to improve co-capture of particulates, SO_3, mercury and other hazardous compounds. Co-capture is discussed further in Section 6.6.

Reducing SO_2 emissions using FGD systems may result in increased greenhouse gas emissions and increased wastes going to landfill. FGD systems consume significant electrical power leading to increased CO_2 emissions and lower SO_2 levels require higher limestone addition rates. These tradeoffs should be considered when deciding on an acceptable level of SO_2 capture.

5.1.2 SO_2 Reduction by Fluidized Bed Combustion

SO_2 can also be removed in a fluidized bed combustion system by injecting calcium-based sorbents along with the coal. Fluidized bed systems fire a larger particle size coal that is either suspended in a bubbling fluidized bed (BFBC) or in a circulating fluidized bed (CFBC). Fluidized bed systems are generally not considered competitive with PCC for coal-fired power plants larger 200 MW but are selected for fuels that are difficult to burn in a PCC plant, such as coals with high moisture, ash and sulphur contents.

Manufacturers of fluidized bed systems continue to improve the effectiveness of in-bed sulphur capture and to optimize a combination of in-bed sulphur capture followed by spray dry scrubbing of the flue gas. Alstom is a leading producer of circulating fluidized bed systems and claims SO_2 removals as high as 98.5% when combining CFBC with further treatment of the flue gas with Alstom’s proprietary Flash Dryer Absorber (Ahman et al., 2002). Techniques for treating and recycling bottom ash and fly ash to maximize the utilization of lime for SO_2 capture have also been developed as a means of reducing lime costs and the amount of waste solids for disposal.

5.2 NO_x Reduction:

In pulverized coal combustion essentially all of the NO_x produced is in the form of NO. N_2O may also be produced in fluidized bed combustion, which operates at lower combustion temperatures. NO_x emissions are of concern due to their contribution to acid rain, to the production of ozone and to the build-up of nitrogen in soils. N_2O is also a concern as a greenhouse gas but is not produced in significant amounts during pulverized coal combustion. The production of ozone is primarily a concern in highly concentrated urban or industrial areas, such as the Eastern U.S. and Japan.

Combustion of coal produces NO_x by the following two routes:

- thermal NO_x – formed by reaction of O_2 and N_2 at high temperatures, or
- fuel NO_x – formed by the oxidation of nitrogen containing species in the fuel.

The relative contribution of thermal NO_x and fuel NO_x is dependent on combustion conditions, including residence time in the flame, flame temperature and oxygen availability. In an uncontrolled coal flame as much as 80% of the NO_x results from fuel NO_x.

With current technologies NO_x emissions are reduced by:

- modifying coal flame conditions in order to reduce NO_x formation (low NO_x burners),
- injecting hydrocarbons to reduce NO_x to N_2 near the flame zone (reburning), and
- treating the flue gas to convert NO_x to N_2.(SNCR or SCR reactors).

5.2.1 Low NO_x Burners

Pulverized coal-fired boilers are either wall fired units with individual burners or corner fired units that maintain a large fireball near the centre. Low NO_x burner systems are available for both styles of furnaces.

Modifying the combustion zone conditions is the most cost effective method for reducing NO_x emissions. Low NO_x burners incorporate some or all of the following techniques:

- reduce oxygen concentrations by minimizing excess air,
- reduce maximum flame temperatures by reducing intensity of mixing,
- inject coal into an initial ‘fuel-rich’ zone to promote conversion of fuel nitrogen to N_2 instead of $NO_{x,}$
- secondary oxygen rich zone to fully burn the remaining hydrocarbons and CO, and
- sometimes a second fuel rich zone is created (reburning) followed by a third oxygen rich zone.

Low NO_x burners have been under development for over 20 years. The techniques used to reduce NO_x also reduce the intensity of the flame and can result in an unacceptable increase of carbon in flyash or carbon monoxide in the stack gas. Sub-bituminous coals are a good fuel for low NO_x burners because of their high combustion reactivity and good burnout properties. Extensive research and full scale testing has gone into the development of modern low NO_x burners as they are one of the lowest cost options (both capital and operating costs) for reducing NO_x emissions.

Low NO_x burners and related systems have continued to evolve since the 2001 review report. Low NO_x burner systems operating in commercial power plants firing sub-bituminous coals can now achieve normal operation lower than 200 mg/m^3 (74 g/GJ) for tangential fired PCC systems with low NO_x burners alone (Henderson, 2005).

BabcockPower Inc. has achieved NO_x emissions below 0.32 lb/MBtu (138 g/GJ) in a 270 MW wall fired unit burning an eastern bituminous coal. The Riley Combustion Venturi (CCV®) dual air zone burner was retrofitted in an existing unit combined with overfire air to achieve these low NO_x levels (Courtemanche et al., 2005).

ALSTOM Power Inc. markets a low NO_x burner system for corner fired utility boilers. ALSTOM has been supplying low NO_x overfire air-based and burner systems since 1970 for reducing NO_x emissions. A power plant operated by NRG Texas LP installed Alstom TFS 2000 low NO_x firing system with over-fire air on two units. The retrofits reduced NO_x emissions from 0.4 lb/mmBtu (172 g/GJ) to 0.15 lb/mmBtu (65 g/GJ).

Advanced process control methods can further reduce NO_x emissions by optimizing the numerous control variables in a low NO_x burner equipped power plant. During stable operation and particularly during load changes, optimum boiler operation is complex with many interacting parameters, such as excess combustion air and flue gas carbon monoxide and NO_x concentrations. An advanced control system based on neural networks combined with ALSTOM LNCFSII low NO_x burner system was installed in a 750 MW tangential fired boiler. Normal operation of the plant with the low NO_x burners achieved mean NO_x levels of 0.163 lbs/mmBTU (70 g/GJ). Implementation of the advanced control system further reduced NO_x by 10% to 0.146 lbs/mmBTU (63 g/GJ) over a wide range of loads (Hocking et al.).

5.2.2 Selective Non-catalytic Reduction (SNCR)

Ammonia compounds when injected into combustion products from 900 to 1100°C will react with NO_x to form N_2. Reagents used in commercial SNCR systems include anhydrous ammonia, urea, and aqueous ammonia. As the temperature window of reaction is narrow, the amount of injection has to be varied with boiler load to prevent excessive slip of unreacted ammonia reagent (ammonia slip) yet maintain sufficient NO_x reduction.

SNCR is relatively inexpensive to install but does not offer NO_x removal levels better than modern low NO_x burners with sub-bituminous coal. The system also has the potential for ammonia slip in the flue gas.

5.2.3 Selective Catalytic Reduction (SCR)

Due to their installation and operating cost and complexity, SCR units are only used when the highest levels of NO_x removal are required. These levels of NO_x removal may be needed in large urban areas where ozone and photochemical smog are serious problems. SCR systems are the most expensive NO_x control strategy and, where required, are usually combined with low NO_x burner systems to minimize catalyst and ammonia injection costs.

Ammonia is injected into the flue gas ahead of the SCR catalyst. The SCR catalyst promotes the reduction of NO_x by ammonia to produce N_2. Optimum temperatures for the reaction are 300 to 400°C. SCR units have been installed primarily in high dust locations before the electrostatic precipitator (ESP) or baghouse. Accurate control systems are required to maximize NO_x reduction while minimizing ammonia slip.

Developments in SCR technology since the 2001 report have centered on catalyst development and control systems to minimize ammonia slip and conversion of SO_2 to SO_3. SO_3 is an undesirable product of SCR systems as SO_3 emissions can contribute to secondary fine particulates formation, visible plumes, and corrosion. Commercial installations of SCR systems have achieved NO_x outputs levels of 65 mg/m^3 or about 24 g/GJ in the U.S. and 30 mg/m^3 or about 11 g/GJ in Japan (Henderson, 2005).

The benefits of reduced NO_x with SCRs must be weighed against the additional capital and operating cost over low NO_x burner alone and the potential for SCR systems to emit other pollutants such as ammonia and SO_3.

5.3 Particulate Reduction

Particulates in the products of coal combustion are primarily entrained ash components with a small amount of unburnt carbon. In pulverized coal combustion boilers, about 80% of the ash is carried out of the furnace chamber entrained in the flue gas. The other 20% of the ash is removed as 'bottom ash' from the bottom of the furnace chamber. The particle concentration and size distribution will be determined mainly by coal ash content and fineness of pulverization. Particulate is removed with either electrostatic precipitators or with baghouse filters. The removal efficiency of these devices decreases with decreasing particle size. Particles that pass through these devices are primarily smaller than 10 microns (PM10) with about 50% smaller than 2.5 microns (PM2.5).

Most of the trace metals in coal will be removed with the ash particles. Mercury and selenium can remain in the vapour phase and pass through particulate removal equipment.

Electrostatic precipitators and baghouses are the only current technologies used for particulate removal at the large scale of utility boilers.

5.3.1 Electrostatic Precipitators (ESP)

ESP's are the dominant technology currently installed in coal-fired power plants in Alberta. ESP's create an electric field between electrodes and flat collector plates. As flue gas passes through the ESP, ash particles are charged in the field and attracted to the grounded collector plates. The deposited flyash is removed by occasional rapping of the collector plates followed by collecting the ash in hoppers below the plates.

ESP's can achieve up to 99.9% particulate removal and ash emissions as low as 8.6 ng/J. ESP's are limited in efficiency of removal of particles <4 µm. Wet ESP's can achieve higher particulate removals but they have not yet been demonstrated at a utility scale (see Section 6.3).

There have not been any significant developments in dry ESP technology since the 2001 report.

5.3.2 Baghouses

Baghouses are used as an alternate to or in combination with ESP's for particulate removal. They are typical large enclosures containing numerous porous fabric filter bags. Ash builds up as a dry cake on the dirty side of the bag. This cake improves fine particle removal and can help to remove other pollutants such as trace metals, chlorine, and SO_2. Filter cake is removed periodically by shaking or injecting a pulse of backflow air. The filter cake then drops to the hopper at the base of the baghouse.

Baghouses are a well proven technology. They are more effective than ESP's for removing ash particles <10 microns and their performance is not affected by composition or high resistivity properties of ash from low sulphur coals. Maintenance costs can be significant, as filter bags have to be replaced periodically.

Several commercial installations of baghouses on pulverized coal utility boilers achieve particulate removal >99.9%, with a resulting particulate emission level of 6.5 to 8.6 ng/J.

There have not been any significant improvements in baghouse technology since the 2001 report. Improvement in filter bag durability and the use of additives to enhance the co-capture of SO_2 and mercury in the baghouse are two areas of continuing development.

5.4 CO2 Reduction

The combustion or gasification of coal to produce electricity results in emissions of carbon dioxide (CO_2). Without separation and recovery of CO_2, the quantity of CO_2 emissions per unit of electricity production is mainly a function of the overall efficiency of converting coal chemical energy to electricity or other useful forms of energy.

5.4.1 Efficiency Improvements

The largest potential for improved efficiency is to use the waste heat from the steam cycle for industrial or district heating purposes. This option is only available for power plants located adjacent to a city or industrial complex. New, higher efficiency technology, such as ultrasupercritical PCC or IGCC plants reduce CO_2 emissions per unit of electricity produced. There are also technology development projects to improve the efficiency of existing PCC plants.

Retrofitting older plants with new technology can lead to efficiency improvements that reduce the emissions of CO_2 per unit of electricity production. The steam cycle portion of a coal-fired plant has the most scope for improvement. The steam turbine is a major component that has seen significant improvements in the design of turbine blades and steam paths that have lead to improved efficiency of converting steam energy to electricity. Schararschmidt et al., 2005 report on a rebuild of the steam generator at a 705 MW lignite-fired plant in Germany. The steam turbine at this 25 year old plant was rebuilt with new rotors, inner casings and turbine blades along with improvements to the cooling tower and addition of a combustion air preheater. After these upgrades, the plant efficiency increased from 38.45% to 40.45% with a reduction of CO_2 emissions of 193,000 tonnes/year. The cost of the CO_2 savings was estimated to be 5.6 euro/tonne of CO_2. The cost effectiveness of retrofit solutions to reduced CO_2 emissions by rebuilding the steam turbine system will be site specific.

Pre-drying of the feed coal with waste heat from the power plant can improve the overall efficiency of a power plant firing high moisture coals. A U.S. DOE sponsored project at the Coal Creek Station in North Dakota is demonstrating a pre-drying technology at one quarter of full scale for a 546 MW plant. Pre-drying the coal would improve overall plant efficiency and also reduce the flow of flue gas through flue gas cleaning equipment. By drying one quarter of the plants coal requirement, the boiler efficiency improved 0.3 percentage points. The benefit of pre-drying will depend on the initial moisture content of the coal.

5.4.2 CO2 capture

Several studies show the distinct advantage of IGCC with CO_2 capture over PCC or SCPC plants with current systems to separate CO_2 from flue gas. Systems for separating CO_2 from the synthesis gas produced from coal gasification are commercially available and well proven in the natural gas industry. With current technology, incorporation of CO_2 capture into an IGCC system increases the cost of electricity by about 36% as opposed to an estimated 68% for a SCPC plant (Narula 2005). Further developments in CO_2 capture are discussed in Section 6.5

The potential exists in Alberta for CO_2 storage in underground aquifers, deep coal seams and depleted oil and gas reservoirs. The recovery of CO_2 from coal gasification systems and sequestration by CO_2 enhanced oil recovery is already practiced at a commercial scale in the Weyburn field in southern Saskatchewan.

5.4.3 Use of Solid Wastes in the Concrete Industry

A short term method of indirectly reducing CO_2 emissions is through the utilization of power plant fly ash as a raw material for cement production or as a direct cement replacement. Fly ash from pulverized coal combustion often has cementatious properties and fly ash from sub-bituminous coals can have several beneficial properties when added to cement. For every tonne of Portland cement displaced by fly ash, CO_2 emissions are decreased by about 1 tonne. Both fly ash and bottom ash are currently used in the concrete and construction industry worldwide with active research efforts to increase the proportion of these solid wastes that are utilized rather than sent to landfill (Smith, 2005).

Several coal-fired power plants in Alberta currently sell a portion of their fly ash to the cement industry. Overall in Canada, only 20% of the fly ash suitable for use as a cement additive is currently used in concrete applications (Bouzoubaa and Fournier, 2005). Barriers to increased use include transportation and storage costs, regulations, and fly ash properties. Implementing technologies such as low NO_x burners and SCRs can also reduce fly ash quality by resulting in an increase of carbon and ammonia in the fly ash.

5.5 Supercritical Pulverized Coal Combustion (SCPC)

Supercritical pulverized coal plants are similar to conventional pulverized coal combustion plants and use the same technologies to control emissions of SO_x, NO_x and particulates. The overall efficiency of conversion of coal to electricity is primarily a function of the temperature and pressure of the steam entering the steam turbine-generator set. Supercritical plants operate with higher steam pressure and temperatures than conventional sub-critical PCC plants and can operate with several percentage points higher efficiency than conventional PCC plants. Even though the same technologies are used to control SO_2, NO_x and particulate emissions, a supercritical plant has lower emissions per unit of electricity produced due to its higher efficiency of electricity production.

New materials and designs continue to be developed to increase the operating pressure and temperature of SCPC plants. Current SCPC plants are operating at steam temperatures above 600°C and pressures of 250 bar resulting in efficiencies of 43% HHV. This compares to conventional PCC efficiencies of typically 35%. Based on emissions per unit of electricity production, this efficiency improvement translates to reduction of SO_2, NO_x, particulates, and CO_2 emissions of 23%. Materials research is targeting boiler materials for steam temperatures up to 700°C which would yield efficiencies of 48%.

6.0 MID-TERM TECHNOLOGIES

Mid-term technologies are those processes that are currently undergoing demonstration scale tests and may be commercially available in the next 5 to 10 years. Several technologies, such as Integrated Gasification Combined Cycle (IGCC), have operating commercial size power plants but all of these projects have significant government contributions to their construction and operation. These government subsidies were required to offset the risk of installing equipment with poorly defined operating cost, performance, and lifetime. The technologies described will either result in lower air pollutant emissions or will reduce the cost of meeting current emissions limits.

6.1 Integrated Gasification Combined Cycle (IGCC)

Integrated Gasification Combined Cycle (IGCC) technology uses a combination of coal gasification, gas-fired turbines, and steam turbine cycles to improve the efficiency of converting coal to electricity. Coal is converted to synthesis gas (mainly a mixture of methane, carbon monoxide and carbon dioxide) in a gasification reactor followed by gas cleaning to remove particulate, chlorides and sulphur compounds (H_2S and COS) and volatile metals (such as mercury) followed by combustion of the clean gas in a gas turbine generator set. Waste heat from the gasifier and from the exhaust of the gas turbine is used to generate steam, which generates additional electricity in a steam turbine generator set.

IGCC has advantages over conventional and supercritical pulverized coal combustion including:

- high efficiency of electricity generation relative to PCC plants,
- feedstock flexibility (coal, petroleum coke, biomass),
- lowest pollutant emissions of current technology for coal, approaching emissions levels of natural gas fired power generation,
- less solid wastes (up to 50% less),
- lower water consumption (two thirds of a conventional PCC plant),
- potential for staged installation of new capacity,
- potential to produce other products (e.g. methanol, ammonia, hydrogen) and to integrate with petrochemical facilities,
- removal of mercury, and
- recovery of CO_2 with conventional, proven technology.

Gasification is a commercially proven technology for petroleum pitch and petroleum coke feed. Coal-fired gasification is also well proven technology for chemical production. However, IGCC is still considered a mid-term technology primarily because:

- capital costs are still 15 to 20% higher than a SCPC plant, (Rigdon and Schmoe, 2005)
- cost of electricity is about 10% higher than a SCPC plant (Rigdon and Schmoe, 2005),
- lower availability than SCPC, especially during first few years of operation, and
- reliability is lower.

The disadvantages of IGCC as compared to PCC or SCPC plants have decreased since 2001 as a result of accumulated operating experience with commercial gasifiers, design improvements to IGCC systems and continuing reduction in allowable emissions. The claim that IGCC capital and operating costs are higher than an equivalent SCPC plant is based on meeting existing emission requirements. If the SCPC plant were to achieve the same emissions of NO_x, SO_x, and mercury as a current IGCC design, the capital and operating costs differences drop dramatically. If CO_2 capture is required, the IGCC plant has a clear cost advantage. Figure 1 illustrates these effects as reported by Rigdon and Schmoe, 2005. In addition, greater than 90% mercury removal has been commercially demonstrated by Eastman Chemicals in their gasifier while mercury removal systems are still in the demonstration phase for coal combustion systems.

The argument that gasifiers are unreliable with unacceptable availability also seems to be decreasing. Eastman has achieved an onstream time of 97.7% for their gasifier over a three year period (Trapp, 2005). The Wabash, Polk and Buggenum IGCC projects all had outages of less than 5% in 2002 and 2003 (Higman and Steele, 2005). Operating IGCC plants have also demonstrated significantly lower emissions than SCPC plants. The Teco Energy Polk IGCC plant has achieved emission level of 0.12 lb/MMBtu (52 g/GJ) for SO_2, 0.04 lb/MMBtu (17 g/GJ) for NO_x and less than 0.004 lb/MMBtu (1.7 g/GJ) for particulate (www.gasification.org/Docs/Tampa%2006/Hornick.pdf).

IGCC systems appear to have more scope for future increases in efficiency of electricity generation and for further reduction of pollutant emissions. Figure 2 illustrates projected developments in emissions of NO_x and SO_x from IGCC and SCPC systems, with IGCC maintaining a significant lead in low emissions at present and in the future. In addition IGCC systems can accommodate >90% capture of mercury with current technology with minimal impact on operating cost. If CO_2 capture is required in the future, the cost of electricity for an IGCC plant will be increased by about 36% while the cost of electricity from a SCPC plant will increase by 68% (Narula 2005). With further IGCC design improvements, costs are decreasing as opposed to the increasing costs of PCC plants due to the increasing costs of flue gas treatment to meet tightening emissions limits.

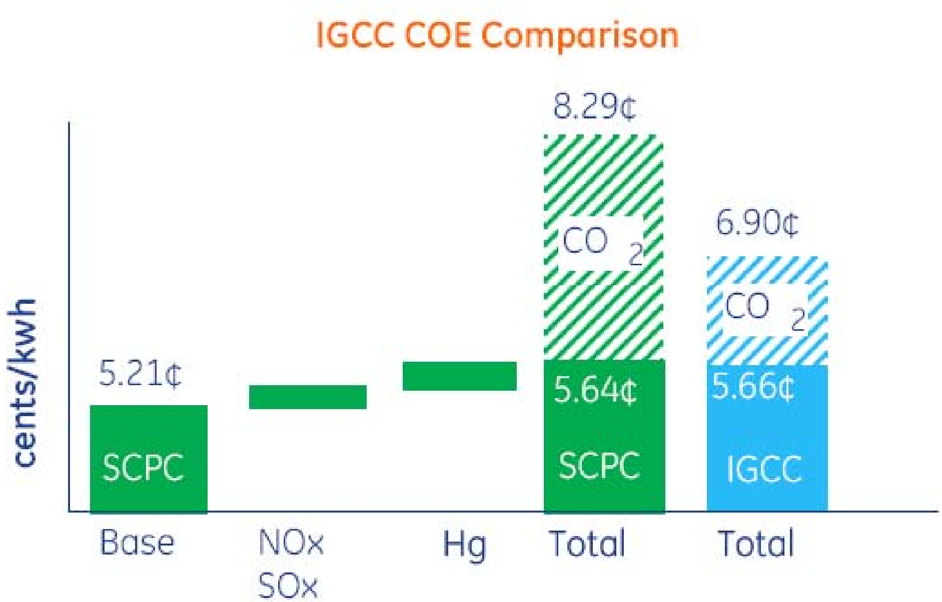

Figure 1: Cost of Electricity Comparison for Equivalent Emissions (from Rigdon and Schmoe, 2005)

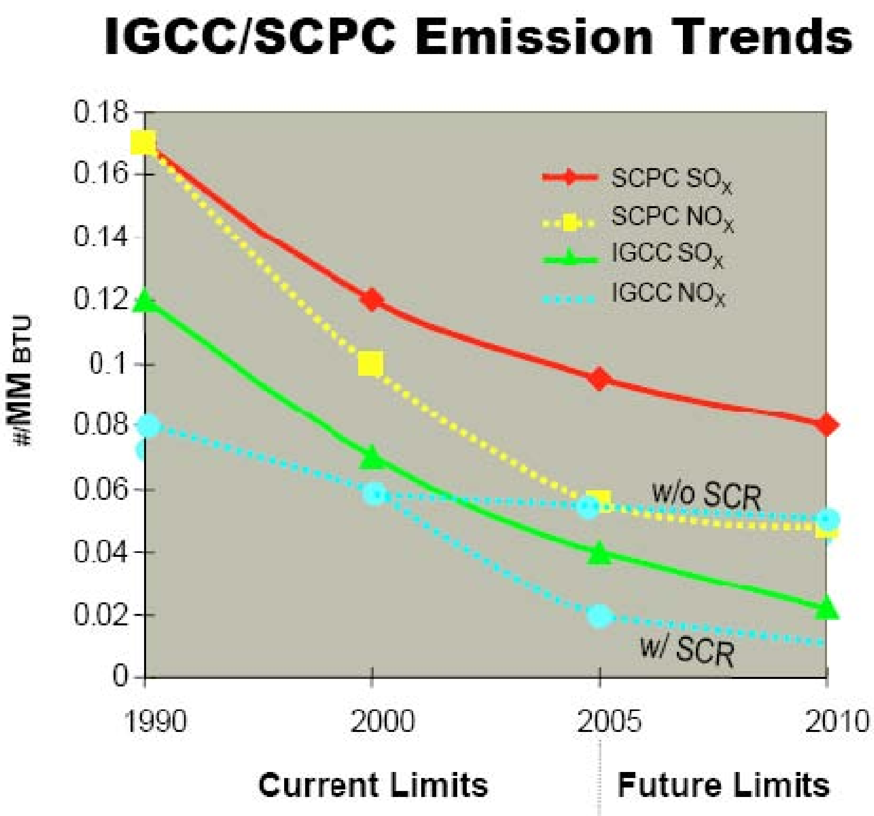

Figure 2: Potential Emissions Reductions for IGCC and SCPC (from Narula, 2005)

A recent design study sponsored by the U.S. EPA compared the costs and environmental footprint of IGCC, conventional PCC, supercritical PCC and ultra-supercritical PCC (Nexant, 2006). The study examined design cases for bituminous, sub-bituminous and lignite coals. The technology options were restricted to those projected to be commercially applied by 2010. IGCC emissions were projected to be less than any of the PCC technologies for all air pollutants and that IGCC plants would generate less than half of the solid waste as a PCC plant with wet flue gas desulphurization. Fresh water requirement was also 60% or less of the water requirement for the PCC plants. The IGCC cases did not include SCR for the syngas turbines while all of the PCC cases included SCR systems. NO_x emissions from the IGCC plant could be reduced further by installation of an SCR system after the gas turbines. Projected capital costs for the IGCC plants were from $150 to $900/kW higher than the PCC plants, with the highest cost for IGCC plants operating on lignite. Projected operating costs for the IGCC plants firing bituminous coal were lower than the PCC plants and comparable when firing sub-bituminous coals. When CO_2 capture is required, the IGCC system had a significant capital and operating cost advantage over the PCC plants. Table 1 shows results from Nexant, 2006, comparing the emissions from an IGCC plant and a supercritical PCC plant firing subbituminous coal, both designed with existing technology.

Table 1: Design Study Comparison of IGCC and Supercritical PCC
(for subbituminous coal, data from Nexant, 2006)

	IGCC without SCR (slurry fed gasifier)	**SCPC with SCR**
efficiency (%HHV)	40.0	37.9
NO_x (g/GJ*)	41	62
SO_2 (g/GJ*)	11	68
CO (g/GJ*)	28	104
particulate (g/GJ*)	6.5	12.5
water use (lb/MWh*)	5,010	8,830
solid waste (lb/MWh*)	45	67

*weight of emission per gross GJ of electricity production

Due to the higher installed cost than a SCPC power plant and concerns about reliability and availability, utility companies are still hesitant to build commercial IGCC plants. Early in 2006, the United States introduced two tax credits to accelerate the adoption of IGCC technology for electric power generation (www.netl.doe.gov/business/faq/tax_credit.html). The coal project credit will pay up to 20% of the installed cost of advanced coal projects using IGCC for electricity production. The gasification project credit will pay up to 20% of projects that use gasification to convert solid or liquid hydrocarbon materials to a synthesis gas for direct use or for chemical or physical conversion. The total amount of these two programs is $1.65 billion. As of August, 2006, these incentive programs were oversubscribed with 45 applications for new IGCC plants in the U.S. The next few years will see the installation of several commercial IGCC systems in North America.

Since the 2001 report, there has been several ownership changes and consolidation of gasification processes, including:

- GE acquired the Texaco gasification process and has joined forces with Bechtel to develop standard 'reference' IGCC plants.
- Siemens Power Generation Group acquired the German firm Future Energy GmbH and their entrained flow gasifier.
- Conoco-Philips acquired the E-Gas entrained flow gasifier.

This consolidation reduces the technical and economic risk of building an IGCC plant as a single entity can supply both the gasifier and the power production equipment.

To address concerns about the high capital cost and lower plant availability, each of the major gasifier developers are developing standard plant designs or 'reference power blocks'. An example is the Siemens Power Generation Inc. reference power block project based on Siemens gas turbines and the ConocoPhillips E-gas coal gasification technology (Feller and Gadde, 2006). GE has formed an alliance with Bechtel to design a 630 MW reference IGCC plant with an objective to reduce by 50% the additional capital cost of an IGCC plant over a SCPC plant (Rigdon and Schmoe, 2005). The reference plant design is planned for completion by end of 2006. The anticipated benefits of a standard reference plant include:

- reduced CAPEX costs by standardizing component designs,
- optimizing integration of the gasifier and power generation portions of the plant,
- advanced engineering to improve operability and fuel flexibility,
- target of 85% availability on syngas; higher with natural gas backup fuel,
- turnkey IGCC offering, and
- single point responsibility for firm price, schedule, performance and emissions guarantees.

6.2 Pressurized Fluidized Bed Combustion (PFBC)

Pressurized fluidized bed combustion (PFBC) technology uses a combination of coal-fired gas turbine and a steam turbine cycle to improve the efficiency of electricity generation. Coal is combusted in a fluidized bed to produce a gas up to 900°C. This gas is then cleaned to remove sufficient particulate to allow injection into a 'ruggedised' gas turbine-generator set. Steam is generated from heat exchangers located in the fluidized bed and passed through a steam turbine-generator set. The flue gas exhaust from the gas turbine is further treated to remove NO_x and particulate, depending on the level of emissions to be met.

Since the 2001 report, development and demonstration activities in PFBC have decreased. Both the fluidized bed design by ABB (now part of Alstom Power) and the circulating fluidized bed design by Foster Wheeler are no longer actively supported by the manufacturers (Fernando, 2004). Hitachi was a major developer of PFBC in Japan but there are no recent reports of activity in PFBC by Hitachi.

6.3 Wet Electrostatic Precipitators for Particulate Control

Dry electrostatic precipitators are widely used in the coal-fired power generation industry. Dry ESP's typically remove >95% of the ash particulate from the flue gas. Fine particulates (PM2.5) are difficult to remove with dry ESP's partly due to re-entrainment during rapping of the plates for ash removal.

Wet electrostatic precipitators are currently used in the treatment of waste incineration flue gas and are being developed for coal-fired power plants. Wet electrostatic precipitators are being developed to address issues of PM, SO_3 and mercury emissions associated with coal fired power plants in conjunction with progressively stricter regulations. Laboratory scale testing of this technology has been successful and has led to pilot testing at Southern Energy's Dickerson Station. In this instance, a hybrid system was used where a wet unit was placed downstream of a dry ESP unit. This hybrid system achieved high collection efficiencies of both SO_3 and PM2.5 and opacity as low as 10% was reached (Altman, 2003). However, because of time constraints, mechanical difficulties associated with the project could not be addressed and the project was terminated. Other implementations of wet ESPs have also been done at the Northern State Power's Sherco Station, were 11 units of tubular wet ESP's were positioned downstream of the FGD unit for two 750 MW boilers. Again, opacity was successfully reduced to less than 10% for the two boilers and an emission rate of fine particulate of less than 0.01 lbs/Mbtu (4.3 g/GJ) was obtained. As well, pilot tests were also done at the First Energy Bruce Mansfield Station where the system was positioned following the FGD unit. The removal efficiencies obtained with this metallic wet ESP system are listed in Table 2. This technology has also been used in a number of coal fired power plants in Japan (Nalbandian, 2004).

Table 2 Summary of Wet ESP Removal Efficiency Comparison at Bruce Mansfield Station (Croll-Reynolds et al., 2004)

Collection Material	H_2SO_4	PM2.5	Elemental Hg	Oxidized Hg	Particulate Hg
Metallic wet ESP	88%	93%	36%	76%	67%
Membrane wet ESP	93%	96%	33%	82%	100%

At this point, the wet ESP systems have proven their capabilities for PM and SO_3 emission control. Their promising role in a total emission control system has led to their integration in multi-pollutant control systems such as Powerspan's ECO process.
(http://www.powerspan.com/technology/scrubber_overview.shtml).

Wet ESP technology is being improved further to address mercury emission issues. To achieve this, MSE Technology Applications, Inc. and Croll-Reynolds Clean Air Technologies, Inc. have developed a system where a mercury oxidizing reagent is injected in the flue gas stream, effectively oxidizing the elemental mercury which then takes the form of small particulates. This plasma enhanced electrostatic precipitation (PEESP) is still in its developmental stages. Initial laboratory scale test indicated that removal efficiencies of 79% of the elemental mercury could be achieved. A pilot scale study funded by EPRI has been implemented at Southern Company's Alabama Power Plant Miller in August 2004 and should provide more information regarding the efficiency of such a system (Altman, 2004).

Even though the efficiency of wet ESP technology has been demonstrated at the power plant scale, many disadvantages are associated with such systems, the first of which is the need for expensive corrosion resistant materials. In an effort to address this, a membrane wet ESP has been designed by Ohio University, Southern Environmental Incorporated and Croll-Reynolds Clean Air Technologies where the metal plate is replace with a fabric membrane. This membrane wet ESP system is used in hopes of eliminating the disruption of the field due to water spraying, the formation of dry spots and the corrosion of the surfaces which are issues encountered with metallic wet ESP systems. A comparison test was done at First Energy's Bruce Mansfield Pilot Plant under funding from the DOE where the membrane wet ESP was compared to a plate wet ESP. The membrane system was seen to have similar and/or better collection efficiencies for PM, SO_3 and mercury as shown in Table 2. Due to the lower cost of the membrane material, membrane wet ESP systems could lead to savings between 8-15%. They also require significantly less water than the traditional wet ESP system, reducing operation costs [Caine, 2003]. However, the long term durability of the membrane system is unknown and any savings could be outweighed by having to replace the membrane (Croll-Reynolds et al., 2004). At this point, further long term testing of this technology is required.

6.4 Mercury Control

Mercury exists in trace amounts in coal. In 1995, the utility industry in the United States produced 32.6% of the manmade mercury emissions in the U.S., primarily from coal-fired power plants. During the combustion of coal, mercury is emitted in the vapour phase as both elemental and oxidized mercury and may also be present in the particulates.

In 2005 the U.S. EPA issued final rules for regulating mercury emission from coal-fired power plants with the objective to reduce coal-fired mercury emissions by 70%. This requirement will be phased in over 12 years using a 'cap and trade' program. Although several processes for mercury removal are in development or the demonstration phase, there are still no commercially available fully demonstrated methods for mercury removal from PCC and SCPC plants.

Both the U.S. Department of Energy and industry are participating in several projects to development mercury capture technologies. Mercury capture appears to be more effective in coal combustion systems firing bituminous coals and less effective with sub-bituminous and lignite coals. The ratio of ionic to elemental mercury in the flue gas is higher with bituminous coal combustion and ionic mercury is more effectively captured in existing equipment such as scrubbers. Methods being developed to reduce mercury emissions include:

- precombustion cleaning to remove ash (suitable for eastern bituminous coals),
- modify combustion process to increase unburned carbon in fly ash which then acts to adsorb ionic mercury (www.epriweb.com/public/000000000001012186.pdf),
- add halide salts to coal or boiler to increase ionic to elemental mercury ratio,
- blend bituminous coal in the feed of a sub-bituminous coal power plant,
- promote co-capture of mercury in the FGD scrubber units designed to capture SO_2 by increasing the ratio of ionic to elemental mercury and adding additives to the scrubber solution,
- promote oxidation of elemental mercury in SCR equipment designed to reduce NO_x. The oxidized mercury can then be removed in downstream FGD units, and
- inject solid sorbents (typically treated activated carbon particles) to specifically capture mercury.

Most of the development of mercury specific removal equipment has focused on injection of activated carbon sorbents upstream of a baghouse. A negative impact of this technology is the carbon contamination of fly ash that prevents its sale as a cement additive. To avoid this problem EPRI has developed a process, TOXECON™, that injects sorbent after the primary fly ash removal followed by a second baghouse to capture the mercury sorbent. The process is currently undergoing full scale tests (www.epa.gov/bns/reports/stakesdec2005/mercury/Michaud.pdf).

The U.S. Department of Energy continues to fund projects developing and demonstrating new mercury capture technologies (www.fossil.energy.gov/news/techlines/2006/06005-Mercury_Projects_Selected.html).

A second major focus, suitable for PCC or SCPC plants with wet flue gas desulphurization, is the development of methods to oxidize elemental mercury to form compounds that would be captured in the SO_2 scrubber. One example is a unique method that has been developed by the U.S. DOE NETL laboratory is photochemical oxidation (Granite et al., 2006). This process uses ultraviolet light from a mercury lamp to excite any non-oxidised mercury species leading to oxidation of elemental mercury. Oxidized mercury species are effectively removed by current wet SO_2 scrubbers, wet electrostatic precipitators, or baghouses. Pilot testing at an operating coal-fired power plant is planned for late 2006.

In contrast to coal combustion, mercury removal is commercially proven technology for coal gasification systems. Essentially all of the mercury is present in elemental form in the syngas produced from coal gasification. Eastman uses coal gasification to supply synthesis gas for chemicals production. Over the past 21 years, Eastman has been treating the syngas with a packed bed absorber to remove over 94% of the mercury. The cost of mercury removal from an IGCC plant using the same technology is estimated to be less than $0.25/MWh (Trapp, 2005)

6.5 CO2 Capture Technologies

Research has been ongoing in identifying cost effective technologies for CO_2 capture from PCC and SCPC plants. The U.S. DOE has established a carbon capture research project (http://fossil.energy.gov/programs/sequestration/capture/) which targets finding technologies that would lead to at least 90% of the CO_2 emissions while increasing the cost of electricity by a maximum of 20% for combustion based power plants. Through a comparative study, it was found that the best suited technology to achieve this would be an aqueous ammonia capture system aimed at the capture of CO_2, SO_2 and NO_x [U.S. DOE 2005 and Ciferno, 2005]. The technology behind such a system was developed by the Powerspan Corporation and the National Energy Technology Laboratory through a cooperative research and development agreement (CRADA). Comparison done indicated that with the aqueous ammonia process, an increase in cost of electricity of only 21% or only 18% with an ultra-supercritical steam cycle could be obtained, compared to 66% for a traditional amine scrubbing system. Pilot testing of this process integrated with the already demonstrated ECO system has been announced in September 2005 by First Energy for its Burger Plant. This trial will serve to confirm the efficiency and cost of such a system and provide further assessment of the feasibility of incorporating such a system in coal fired power plants. The objective of this development would be a CO_2 capture process that could be retrofitted to existing PCC plants or incorporated into new plants.

Further technology developments and demonstration plants are needed to reduce the costs of CO_2 separation for both PCC and SCPC plants.

6.6 Co-Capture of Pollutant Emissions

In an attempt to reduce both capital and operating costs of flue gas emissions control, many organizations in the U.S. are developing technologies to capture more than one pollutant with one flue gas treatment system. Wet flue gas desulphurization equipment consumes as much as 2% of the plant's electricity output, leading to higher CO_2 emissions per unit of electricity to the grid. Any methods that could co-capture other pollutants with the same FGD equipment would be beneficial.

Several companies are looking at additives or other flue gas treatment methods to convert NO_x and mercury to compounds that can be captured in the wet scrubber system typically used to remove SO_2. The following describes two examples of co-capture systems under development.

6.6.1 ECO process

The ECO (Electro-Catalytic Oxidation) (Boyle, 2005) process has been developed and implemented by Powerspan (http://www.powerspan.com/technology/scrubber_overview.shtml). This consists of a system that integrates technologies to reduce emissions of SO_2, NO_x, particulate matter and mercury from coal fired power plants. The system is composed of an ECO Reactor which is a dielectric barrier discharge reactor, an absorber vessel and a wet ESP system. It is intended for this system to be positioned in commercial applications downstream of a dry ESP or fabric filter. The ECO reactor consists of a dielectric barrier discharge which serves to oxidize some of the NO, SO_2 and Hg found in the flue gas. The effluent then goes through the absorber vessel which is an ammonia scrubber where the NO_2 and SO_2 are removed. Following this, the wet ESP system serves to remove the particulate matter, the oxidized mercury, and other aerosols present. The ammonium sulfate by-product is collected and used to make fertilizer which is sold to market.

Through partnership with First Energy, pilot scale testing was done at the FirstEnergy's R.E. Burger Plant near Shadyside, Ohio in 2003. The pilot plant processed 1,500–3,000 scfm of flue gas or 1% of the flue gas produced from the 156 MW coal fired unit. The pilot scale test confirmed that removal efficiencies of 98% for SO_2, 90% for NO_x and 85% for mercury could be achieved. Commercial demonstration of the process has followed where the unit processed 110,000 scfm of flues gas or 50 MW equivalent of the total flue gas produced from the 156 MW coal fired unit. The unit was found to be successful during a reliability assessment of 180 days done in 2005. Removal efficiencies obtained were 98% for SO_2, 90% for NO_x and 80-90% for mercury and less than < 0.01 lb/mmBtu of PM2.5 at the outlet. The system also generated 18,500 tons of liquid ammonium sulfate fertilizer which was sold to market. Following this, First Energy announced in September 2005 that it was planning to integrate a 215 MW ECO system at its Bay Shore plan in Oregon, Ohio. Powerspan estimates the capital cost of such units as being 10-20% less than conventional technologies.

6.6.2 Airborne Process

Airborne Technologies has a process at the demonstration scale that uses dry sodium bicarbonate coupled with wet sodium scrubbing to co-capture SO_2, NO_x, and Hg emissions (Johnson, et al., 2005). The system produces an ammonium sulphate fertilizer as a by-product and a carbon dioxide stream and regenerates the spent sodium carbonate for reuse.

Primarily designed for SO_2 removal, the Airborne process has been adapted to co-capture other pollutants. The addition of oxidants to the scrubbing solution increased the capture of both NO_x and Hg in the scrubbing solution during pilot scale tests.

The Airborne process has been demonstrated at the scale of 5 MW and a full scale demonstration of the process is planned by Peabody Energy on a 300 MW power station.

7.0 LONG-TERM TECHNOLOGIES

Long-term technologies are those processes that are currently undergoing development at a pilot scale or smaller. In addition to reductions in conventional air pollutants, long term technology development also targets the separation of CO_2 for ultimate sequestration. Government research funds make up a large portion of the funding.

There have been no significant developments in the long term technologies identified in the 2001 report. However, since the 2001 report the United States has initiated a major ten year demonstration project known as 'FutureGen'. This project is an industry/government partnership project with participation by several major companies in the United States and by international governments. The objective of this $1 billion project is to build a commercial scale coal-fired power plant that will generate both electricity and hydrogen with near zero emissions to the air.

The plant will use coal gasification combined cycle technology to demonstrate production of both electricity and hydrogen from coal. The plant will also include the separation and capture of CO_2. At the time of this report, the United States Department of Energy was considering a short list of four locations for construction of the FutureGen demonstration plant.

8.0 GLOSSARY

HHV - Higher heating value of the coal; includes heat of condensation of water vapour in combustion products

LHV - Lower heating value of the coal; does not include heat of condensation of water vapour in combustion products

Efficiency %HHV - Efficiency of conversion of thermal energy in coal to electricity, based on HHV of coal

Efficiency %LHV - Efficiency of conversion of thermal energy in coal to electricity, based on LHV of coal; relationship between %LHV and %HHV depends on coal properties, with %LHV being 2 to 5% units higher than %HHV

ESP - Electrostatic precipitators

FGD - Flue gas desulphurization

IGCC - Integrated coal gasification combined cycle with synthesis gas fired turbine combined with steam turbine for electricity generation

g/GJ - grams per gigaJoule (1 g/GJ = 430 lb/MMBtu)

PCC - Pulverized coal combustion, conventional coal-fired power plant

PFBC - Pressurized fluidized bed combustion, combining hot gas cleanup to directly fire a gas turbine with coal combined with steam turbine

SCR - Selective catalytic reduction, uses ammonia injection and a catalyst to reduce NO_x to nitrogen

SNCR - Selective non-catalytic reduction, uses ammonia injection without a catalyst to reduce NO_x to nitrogen

SCPC - Supercritical pulverized coal combustion

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